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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design (U 39 M)	))))	Application 06-03-005 (Filed March 2, 2006)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMMENTS ON THE SUPPLEMENTAL SCOPING MEMO AND ASSIGNED COMMISSIONER'S RULING UPDATING ISSUES LIST, SCHEDULE, AND CATEGORIZATION

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I.

INTRODUCTION

Pursuant to the *Supplemental Scoping Memo and Assigned Commissioner's Ruling Updating Issues List, Schedule, and Categorization*, dated August 22, 2007 (ACR), Southern California Edison Company (SCE) provides these comments on the Rate Design issues identified in the Issues List in Attachment A of the ACR. The Issues List presents over 70 questions related to dynamic pricing policy, and therefore SCE does not endeavor to address each of the questions. Rather, these comments focus on what SCE believes to be the key issues to developing and implementing a well-designed dynamic pricing policy. In accordance with the ACR's directives, these comments are structured according to the ten categories of rate design issues enumerated in the Issues List.

SCE's comments are consistent with its recently filed Edison SmartConnect™ Phase III filing (A.07-07-026). Additionally, coordination with the Demand Response Cost Effectiveness Proceedings (R.07-01-041) and the Independent System Operator's (ISO or CAISO) Market

Redesign and Technology Update (MRTU) will be important in developing an effective dynamic pricing policy.

With respect to general policy direction for dynamic rates, adhering to the principles of marginal cost pricing and applying those principles to the unbundled rate components suitable for dynamic pricing, namely the generation component, will ultimately deliver the most efficient rate designs that meet public policy objectives. The long term objective should be to enable reliable demand response (DR) to be bid into the resource mix and be economically dispatched in the same manner as supply-side resources.

SCE's comments recognize the significance and complexity of the issues, and the importance of coordination and discussion between all interested parties and the California Public Utilities Commission (Commission) regarding the resolution of dynamic pricing issues. As such, many of SCE's comments contain directional input toward the resolution of dynamic pricing issues, rather than a proposed solution. SCE looks forward to working with all interested parties in formulating California's dynamic pricing strategies.

II.
DISCUSSION

A. Objectives of Dynamic Pricing and Time-Differentiated Rates

1. Key Policy Issues

From SCE's perspective, the key policy issues in this category are (1) the goals to be achieved through introduction of dynamic pricing and time-differentiated rates; and (2) coordination with other policy and rate design considerations.

2. Goals To Be Achieved Through Introduction of Dynamic Pricing and Time-Differentiated Rates

a) Discussion

The determination of dynamic pricing and time-differentiated rate objectives is a key policy issue that should be developed by the Commission with input from the utilities and other interested parties. SCE agrees that consideration of the following three objectives, already identified by the ACR, is key in developing and implementing a well-designed dynamic pricing policy:

1. Reflect marginal cost of electric service
2. Flatten the load curve
3. Reduce load in the face of short-term supply shortfall

These three policy objectives must be considered in tandem, as it would be relatively easy to flatten the system load (Objective 2) and reduce load during a period of possible supply shortfall (Objective 3) by mandating dynamic rates that charge, for instance, 100 times more during on-peak periods and 500 times more during periods of high temperatures than during off-peak periods to dissuade customers from using their air-conditioning units. Off-setting the excessive on-peak revenues by reducing off-peak prices would lead to an inefficient over-consumption of power in the off-peak period and an inefficient under-consumption of power in the on-peak period.

Objective 1 – reflecting the marginal cost of electric service – should be given the highest priority. Rates that reflect the cost to serve will naturally guide the utilities to the proper system load profile (Objective 2) and reduction in load in the face of a short-term supply shortfall (Objective 3). In general, the Commission can best meet all the objectives by limiting the pricing signal to a long run price and triggering events based on the situations that establish long run system peak demand.

In addition, policy direction provided in the California's Energy Action Plan II (EAP II) loading order is specific in its support of Objective 1 as being the most important:

> EAP II continues the strong support for the loading order – endorsed by Governor Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After ***cost-effective*** efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications.[1]

Finally, when the Commission implemented the unbundling of rate components, it did so to preserve the most efficient pricing of various utility services. Where the rate structures support this policy, the customer who consumes more high cost energy during peak periods should pay a higher energy bill than the customer who uses a greater proportion of lower cost off-peak energy. The rate differentials should have their foundation in cost principles specific to the service at issue. For example, a customer who intermittently places a high demand on its distribution circuit should pay the cost of distribution infrastructure necessary to serve its demand, captured by the customer's non-time-related demand charge.

The policy of unbundling the rate components provides for equitable cost recovery in proportion to the costs incurred by the utility, and should not be modified in this proceeding. Thus, the overall scope of this proceeding should primarily be focused on the estimation and appropriate recovery of generation costs. To the extent that differentials between marginal on-peak and off-peak energy costs are relatively small compared to the generation capacity costs, it is the allocation of these capacity costs to time-of-use (TOU) periods that will dominate the debate over design of dynamic rates.

b) Recommendation

The three listed objectives are appropriate. However, focusing on the objective of reflecting the marginal cost of electric service in dynamic rates should be given the

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[1] Energy Action Plan II, September 21, 2005, p. 2 (emphasis added).

highest priority as it will naturally result in progress towards flattening the load curve and reducing load in the face of short-term supply shortfalls.

3. Coordination with Policy and Rate Design Considerations

a) Discussion

Coordination with R.07-01-041, which will establish the methodology for determining the cost-effectiveness of DR programs, is critically important. The policies developed in this dynamic pricing proceeding will need to be consistent with those reflected in the joint utilities' proposed cost-effectiveness framework (as revised) filed with the Commission on September 10, 2007.[2] This proposed framework provides great detail on the cost-effectiveness of DR programs, and will not be repeated in its entirety here. However, a few of the more pertinent recommendations are worth repeating:[3]

- Recommendation 5 – Cost-effectiveness of DR programs should be evaluated by comparing the costs and benefits of DR programs to the costs and benefits of alternative supply side resources.
- Recommendation 7 – DR programs avoid the need for generation capacity since their function is to reduce customer usage during periods of peak demand.
- Recommendation 10 – Since market prices for generation capacity are not available, they must be estimated. This estimate consists of subtracting the present value of the energy produced by the new generation resource and sold into the market from the present value of the total fixed costs of the new resource (defined as a natural gas fired combustion turbine, or CT).

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2 *Revised Straw Proposals for Demand Response Load Impact Estimation and Cost Effectiveness of Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E), and Southern California Edison Company (U 338-E)* (the Joint Utilities' Demand Response Cost-Effectiveness Filing)

3 For brevity, recommendations are paraphrased.

- <u>Recommendation 13</u> – Capacity benefits of a DR program should be adjusted for differences between the DR program and the capacity value of a new CT. For example, DR programs that can only be called for a few hours a year and only with 24 hours advance notice provide less value than a supply resource that is available year-round with rapid (e.g., 30-minute) start up capability.
- <u>Recommendation 16</u> – Although important, avoided energy costs usually account for only a small share of the total costs avoided by a DR program.

Taken as a whole, these recommendations identify generation capacity costs as the relevant element directly affected by DR and provide guidance regarding cost-effectiveness; i.e., what utilities should be willing to pay to achieve the value provided by DR or alternatively what the utilities should charge for a unit of generation capacity demanded by a customer at different times.

Avoided distribution costs should be generally assigned to system reliability (or direct load control) programs, so we limit their discussion in these comments (which are targeted primarily towards dynamic pricing structures). For the same practical reasons that nodal generation prices would be virtually impossible to manage at the retail rate level, distribution dynamic pricing components would be problematic. For example, because various distribution circuits peak at different times, defining on-peak and off-peak periods for distribution pricing will take on a local nature, similar to nodal prices. Some distribution circuits peak during what SCE's tariffs currently call off-peak period. Because of this, it would be impractical to have time-differentiated distribution charges that match all distribution circuits' loading patterns. Therefore, distribution costs should be recovered in non-time-differentiated charges. However, when a direct load control program can avoid distribution costs, such avoided costs should be provided to the program participants as a direct payment.

b) **Recommendation**

Coordination with other policy and rate design considerations, as well as the DR cost-effectiveness framework should continue to be given a top priority. To the extent that some assignment of value to various externalities can be placed into the cost-effectiveness evaluations, they should be handled in R.07-01-041. Other items noted by the ACR, such as how best to balance the other rate design considerations (e.g., rate stability and simplicity, revenue recovery, and other practical considerations) should be further developed and discussed in the upcoming workshop.

B. **Rate Options**

1. **Key Policy Issues**

From SCE's perspective, the key policy issues in this category are (1) applicability; (2) preferred rate structure, including rebates; and (3) rate simplicity. SCE's comments here are consistent with positions taken in our Edison SmartConnect™ Phase III Application (A. 07-07-026).

2. **Applicability**

a) **Discussion**

SCE supports deployment of optional dynamic rate structures.[4] While an information gap currently exists that prevents adoption of dynamic rate options by a significant number of customers, the availability of load profile information, enabled by advanced metering infrastructures, will allow customers to more accurately assess the rate options available to them. This information will allow SCE to educate its customers and provide targeted marketing on the various dynamic rates. To the extent that lower-cost-to-serve customers migrate to these dynamic rates, a gap will develop between the dynamic price and the Otherwise Applicable

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[4] *See* Edison SmartConnect™ Phase III filing (A.07-07-026) for specific rate options.

Tariff (OAT) increasing the incentive for responsive customers to migrate to these dynamic rate options.

Customer concerns must be considered before any type of default dynamic pricing program is initiated. Since a large percentage of the customers could experience a bill increase under a dynamic pricing structure, the utility should make reasonable efforts to inform customers of the impacts of this rate change. Two program attributes could address this concern. First, the utility could consider a one-year data collection phase to determine the impact of transitioning the customers to dynamic rates without any kind of transition actually taking place. Second, a one-year bill protection program could allow customers to experience the effects of dynamic rates, attempt to respond to them in a "cost-free" trial period, and then make a decision after the bill protection period is over. SCE generally supports bill protections when dynamic rates are implemented on a default or mandatory basis, but cautions that customers may not fully understand the ramifications once their one-year bill protection ends. Ample communication will be required.

However, while the Commission should give consideration to long-term policies to increase participation on dynamic rates, SCE has concerns regarding mandatory dynamic pricing programs. For instance, as the Commission considers removing the suspension of direct access (DA), customers who experience a bill increase as a result of dynamic pricing may abandon bundled service, not necessarily because they are attracted by other Load Serving Entities (LSEs), but because they are attempting to avoid Commission rate mandates. This issue also brings to light the operating principle of cost-effective DR. If the utilities pay too much to bundled service DR participants and recover the costs from bundled service non-participants, the non-participants will face increasing pressure to abandon bundled utility service. In part to address such issues, SCE supports optional dynamic rates.

Additionally, in the long term, SCE envisions better alignment of retail energy prices with wholesale market prices.[5] As the wholesale markets develop, retail energy

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[5] Consistent with the Energy Division's proposed DR goals as articulated in the *Assigned Commissioner's and Administrative Law Judge's Ruling Revising Phase 2 Activities and Schedule*, October 1, 2007, p. A-16.

prices (including dynamic pricing), should be reevaluated to improve transparency and create incentives for smart energy usage.

b) <u>Additional Information or Analysis</u>

The potential customer savings from adopting dynamic pricing structures need to be significant relative to the opportunity cost of the unused electricity to obtain significant demand response. Unfortunately, value of service studies and demonstrated price response results present evidence that avoided cost-based incentives simply do not provide sufficient incentive for business customers to affect their highest priority – their core business activity. The degree to which the value of service effects the demand response equation should be investigated fully to identify the extent to which various customer segments are willing to adopt dynamic pricing structures.

c) <u>Recommendation</u>

The key function of dynamic pricing is to promote the efficient use of generation capacity. Since Direct Access (DA) and Community Choice Aggregator (CCA) customers do not purchase generation services from SCE, they would not be eligible to take service on SCE's dynamic pricing rate schedules.

SCE recommends that the various program structures and participation rates around the country relative to the value of service criteria and/or other market research continue to be assessed to more effectively concentrate activities to achieve the most cost-effective DR results. If the value of a kWh reduction is less for a residential customer versus a business customer due to the options available to them to shift load or other value of service criteria, it would be important to know this in establishing our strategies. This subject could be addressed in the concurrent Demand Response Research Center (DRRC) efforts.

3. Rebates

a) Discussion

As described above, SCE expects that there will be an evolution to an ideal, long-term dynamic pricing solution. Due primarily to the rate restrictions imposed by Assembly Bill (AB) 1X, Peak Time Rebate (PTR) for residential customers will be part of that transition. Accordingly, as detailed in the Edison SmartConnect™ Phase III Application, the advantages of a residential rebate structure include:

- Encourage Demand Response by Maximum Customer Participation. PTR provides the best opportunity to encourage residential customers to provide significant DR given the constraints imposed by AB1X and the limited expected adoption of any opt-in price response program. PTR maximizes customer participation as all residential customers (except those on Critical Peak Pricing (CPP)) will be automatically eligible to earn rebates.
- Provide Customer Savings. PTR provides significant potential customer savings during critical events, thereby changing customer behavior by encouraging DR.
- Comply with Public Policy. PTR is compliant with AB1X and consistent with California's EAP II.

b) Recommendation

Consistent with previous discussions, SCE recommends that the Commission adopt a rebate structure (e.g., PTR) for residential customers while Water Code Section 80110 enacted by AB1X remains in effect. Alternative dynamic pricing structures for residential customers should be evaluated after the provision of this section related to residential rate restrictions is no longer effective.

4. Rate Simplicity

Rate options should be simple for customers to understand. Achieving this objective entails (1) developing simple rate options, and (2) developing tariff and program bundles that are consistent and easy to adopt. As customers understand the rate mechanism that leads to reduced bills, they will be better able to respond appropriately to achieve those savings, furthering the value of the dynamic pricing programs.

C. Components of Dynamic Pricing Tariffs

1. Key Policy Issues

From SCE's perspective, the key policy issues in this category are (1) cost recovery; and (2) coordination with the MRTU.

2. Cost Recovery

a) Discussion

Current mechanisms to recover costs are dependent on the nature of the costs. Customer charges, distribution/transmission facilities charges, generation energy charges, and generation capacity charges should be evaluated separately. SCE's generation capacity costs are estimated to be just a little over 10% of SCE's total costs. By keeping the dynamic pricing designs focused on this small subset of costs, the issue of cost recovery imbalances is mitigated. To the extent the Commission desires to alter the balance between fixed and variable charges, the balance should be achieved strictly through changes in fixed demand charges ($/kW) and variable energy charges ($/kWh) designed to recover utility's generation capacity costs only.

Price response programs are viewed as alternatives to supply-side resources by providing capacity benefits that otherwise would be provided by generation resources. Little, if any, avoided transmission/distribution costs are realized from dynamic pricing programs. This is primarily due to the day-ahead nature of the programs, which limit their effectiveness in promoting grid reliability. Because of this limitation and the potential for generation capacity benefits, cost recovery through dynamic pricing schedules should be limited to generation related costs.[6] By taking a long-term perspective, it is easier to see how price response programs fit into utility cost recovery. In the long-term, dynamic pricing programs should represent actual generation related costs revealed in a capacity market with supply-side and demand-side resources competing to provide the needed capacity.

b) <u>Additional Information or Analysis</u>

Additional information and analysis is needed in the following areas:

<u>Cost Recovery</u>: In order to ensure dynamic pricing and RAR are complementary, it will be necessary to explore long-term regulatory and market structure solutions that allow LSEs to select between supply-side and demand-side resources to meet their capacity needs. Under the current structure, LSEs are required to secure a 15% capacity reserve margin from supply-side resources, thus diluting the "critical need" argument for dynamic pricing programs.

<u>Fixed vs. variable costs</u>: Similarly, in order to determine the optimum balance between fixed and variable charges, additional analysis is needed in the following areas: (1) to what extent can rolling generation demand charges into the energy component facilitate permanent load shifting; and (2) would recovery of some Commission jurisdictional non-bypassable costs through time variant pricing be a viable option to facilitate additional price response?

c) <u>Recommendation</u>

Customer, transmission and distribution costs should be recovered through the same rate structures as today. Existing structures recognize the costs drivers for various

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[6] As discussed further below, under the CAISO's MRTU, wholesale nodal pricing will reflect transmission losses and the cost of transmission congestion. Conceivably, these transmission- related costs which are reflected in wholesale nodal prices could be used for dynamic pricing. However, CAISO prices charged to load serving entities are aggregated into utility-wide load aggregation points at present and utility rates are not differentiated by geographic area, so this is not practical.

utility services, and allocate the costs accordingly. The discussion of cost recovery should focus primarily on generation costs.

A rate design that "optimizes" the proportion of fixed to variable charges should be targeted towards long-term changes in customer behavior through the use of time variant rates, with a goal of flattening the load curve by encouraging permanent load shifting from on-peak periods to mid- and off-peak periods.

3. MRTU Coordination

a) Discussion

The MRTU's primary purpose is to improve grid reliability and management through the use of a nodal pricing framework. Under the MRTU structure, nodal pricing will determine the flow patterns across the grid. This market driven approach is expected to result in more efficient distribution of power and/or infrastructure investment through market forces in the form of nodal price differentials (e.g., infrastructure capacity investment towards congested nodes to reduce the high nodal congestion pricing). The entire framework will consist of 3,000 nodes. While sellers into the MRTU will experience nodal pricing, it is not clear at what level the retail consumers will experience regional average prices for energy (if at all). The MRTU will in effect resemble the Power Exchange energy market established as part of electricity deregulation. The initial phase of the MRTU will not include a capacity market. The ISO will use existing frameworks such as RAR and long-term procurement plans to fill this gap, and will rely on the Commission to determine the structure of a future capacity market.

b) Recommendation

It will be imperative to fully understand how the ISO plans to implement its scarcity pricing requirement to determine how to incorporate capacity prices into the retail rate design.[7] At the very least, temporal alignments will need to be considered as more

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[7] *See* California ISO Straw Proposal, Reserve Scarcity Pricing Design, September 5, 2007.

successful dynamic price response programs are triggered on a day-ahead basis. Elements of incorporating the DR programs into the MRTU processes have been documented in the draft Demand Response Resource Users Guide and the specifics associated with these recommendations will need further refinement.[8] Again, temporal alignments need to be considered as the integration of demand response into the hour-ahead markets presumes a higher level of consumer awareness and response than that documented in California's Statewide Pricing Pilot results or elsewhere.

D. Recovering the Revenue Requirement

1. Key Policy Issues

From SCE's perspective, the key policy issues in this category are how the utilities will recover their revenue requirements, avoiding large periodic rate adjustments, and the proper treatment of over- and under-collections.

2. Recovering the Revenue Requirement, Avoiding Large Periodic Rate Adjustments, and the Proper Treatment of Over- and Under-Collections

a) Discussion

SCE relies on marginal cost studies for revenue allocation and rate design. Dynamic pricing designs should also reflect marginal cost principles, and be revenue neutral to their respective OAT. However, the introduction of dynamic pricing structures will likely increase the occurrence and the magnitude of revenue over- or under- collections. Such imbalances are recorded in normal balancing account mechanisms and would be reflected in the following year's revenue requirement and rate levels. To the extent that the price response programs are optional and dependent upon meter deployment schedules spanning several years,

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[8] *See* www.caiso.com/1893/1893e350393b0.html.

these revenue imbalances are expected to be small for the foreseeable future and the existing balancing account mechanisms should be sufficient.

However, SCE does have concerns regarding this issue. Dynamic pricing structures reflect the utilities' generation capacity revenue requirement into an expected number of (few) high price hours. To the extent that actual year to year price (but not cost) variations occur, revenue recovery from dynamic rates could subject the utilities and customers to large imbalances. If some rate groups are required to adopt dynamic pricing and these revenue and cost imbalances occur as a result of program design, separate rate group balancing accounts should be considered.

As costs are truly avoided by dynamic pricing participants, this will result in a revenue allocation shift away from rate groups with high participation levels in dynamic pricing programs and towards those who prefer more stable (or hedged) rates. This revenue shift could also be accomplished by the existing balancing account mechanisms.

b) Additional Information or Analysis

In order to gauge the potential for these large periodic rate adjustments, parties should explore the revenue impacts associated with their proposed rate structures as a result of expected variations in price conditions and program participation. During the deployment period when rate participation is relatively low and the market matures, sensitivity studies should be conducted with special attention paid to the scarcity pricing mechanisms generated by the MRTU development and their relationship to long run avoided costs.

c) Recommendation

As discussed above, existing balancing account recovery mechanisms will likely be sufficient during the period of advanced meters deployment. To the extent that large blocks of customer load (concentrated in a few rate groups) are subjected to market prices that do not reflect avoided costs, separate rate group balancing accounts may need to be considered.

E. Hedging

1. Key Policy Issues

From SCE's perspective, the key policy issues in this category are (1) potential hedging options; and (2) potential hedging providers.

2. Potential Hedging Options

a) Discussion

In the context of electricity prices, hedging may occur in the wholesale market or at the retail level. Wholesale market hedging refers to the purchase and sale of electricity to minimize the utilities' (or resellers') exposure to price risk. Retail hedging refers to electricity customers' ability to use alternative pricing mechanisms to reduce their exposure to price risk (e.g., dynamic prices).

For purposes of this section, the term "hedging premium" represents the net effect of both cost-based pricing differentials and customers' desire for stable pricing. Customers who respond to dynamic prices will lower their overall bill relative to their OAT by lowering their usage during peak periods. On the other hand, those customers who are more costly to serve, do not anticipate responding, or who are risk averse, may elect to stay on their OAT to maintain their stable rates.

Given that customers who respond to dynamic prices do so to presumably lower their bills, increases to the OAT and/or the dynamic rate would be needed to recover the full revenue requirement.[9] Once this amount becomes significant, this true-up could be a simple ratio adjustment to both rates. (*See* Section D, Recovering the Revenue Requirement, for more discussion regarding balancing account treatment). In any case, customer self-selection into dynamic prices will result in OAT rates that are more stable and slightly higher in aggregate

[9] If costs are reduced commensurately with the decline in revenue, no rate increase would be necessary, though this is not likely in the short run.

relative to the dynamic rate. That is, a "hedging premium" will be reflected in the OAT which will provide rate stability relative to the dynamic pricing structures. This approach provides a stable rate option for most customers.

For more sophisticated customers, a Capacity Reservation Charge (CRC) could be introduced (such as that proposed in SDG&E's current 2008 rate design proceeding, A.07-01-047) whereby customers would pre-pay for the portion of generation capacity costs against which they wish to be hedged and leave themselves exposed to dynamic pricing above this amount. This hedged demand level can vary from zero to the customer's maximum demand and would thus provide the full spectrum of hedging to the customer. Pursuant to D.06-05-038, SCE must default its customers with demands greater than 200 kW to a CPP rate schedule with opt-out capability. A CRC rate option with a full hedge would be equivalent to today's OAT and customers would have the option to reduce their CRC in accordance with the degree of risk/reward they are willing to absorb.

b) <u>Additional Information or Analysis</u>

Proposed only for larger commercial and industrial (C&I) customers, the notion of a CRC represents a significant change from current rate structure and should be evaluated further as customers typically resist these types of mechanisms. Defaulting customers to the fully-hedged structure and explaining potential savings would appear to be a challenge in obtaining significant DR. However, this methodology provides the full spectrum of hedging opportunities from a full hedge (i.e., OAT) to total exposure to dynamic pricing (e.g., CPP/RTP)).

c) <u>Recommendation</u>

As discussed above, SCE recommends the following: (1) for residential and small C&I customers (< 20 kW) where the OAT provides a fixed-average cost recovery for generation capacity, the hedging premium methodology and calculation should be discussed further, including the use of OAT as a dynamic pricing hedge; and (2) for larger customers where generation capacity costs are recovered through time-differentiated demand charges, a

CRC methodology, such as that recently proposed in SDG&E's 2008 rate design proceeding, provides a full spectrum of hedging options and should be analyzed for feasibility, participation, customer response, etc.

3. Potential Hedging Providers

a) Discussion

The potential hedging options should be discussed in context of the potential hedging providers. For those customers who hedge by opting out to their non-time differentiated OAT, the utility will provide the hedge. Customers may also be able to hedge against dynamic pricing impacts by taking service form an Energy Service Provider (if and when the DA suspension is lifted) or via a Community Choice Aggregator (CCA).

b) Additional Information or Analysis

The impacts of allowing customers to hedge their rates by taking service from an ESP or CCA should be assessed.

c) Recommendation

As discussed above, SCE recommends that the utilities should provide hedging options through the OAT and ensure that dynamic pricing policies are not established in such a way as to provide an opportunity to avoid the hedging premium by simply changing energy service provider.

F. Sources of Triggers and Prices for Dynamic Pricing

1. Key Policy Issues

From SCE's perspective, the key policy issues in this category are (1) event "triggers," specifically, what constitutes an "event" and who has the authority to call them; and (2) linkage to market prices and MRTU.

2. Event Triggers

a) Discussion

Dynamic pricing events are typically triggered in response to either short-term or long-term conditions that result in shortage and an increase in price of generation capacity. In the long term, the relevant driver of load in the air-conditioning dependent Southern California region is temperature. In the short run, it is typically limited or restricted supply that manifests itself as a price spike in the marketplace.

Both long- and short-term drivers can be incorporated into triggering events. Since one of the key objectives of dynamic pricing is to modify the system load profile to improve capacity utilization, the trigger definition should correlate to those conditions which drive long-run peak demands. For SCE, this condition is hot weather conditions. In SCE's service territory, inland regions are hot for much of the summer, while shoulder seasons and valley coastal regions are typically hot sporadically during the summer. Accordingly, when hot temperatures reach the valley coastal regions, air-conditioning loads in this region materialize and drive the system peak. For system planning purposes, the correlation between temperature and system load typically follows a 3-day heat build-up cycle with system demands typically driven by a 3-day weighted temperature average of 60%-30%-10% of day of, previous day, and 2-day previous maximum temperature. This would probably be the most precise temperature trigger, though SCE has used a single previous day's temperature to establish varying price profiles (e.g., Schedule RTP-2).

Alternatively, while temperature is a good predictor of system load, there is no reason why utilities cannot use a forecasted system load to trigger their price response programs. The system load forecasts would include temperature build ups as part of their forecasting algorithms, but would also include day-of-week variables and societal components (e.g., post Labor Day school day) that may influence peak demands. One variant of this type of trigger might be a percentage of the 1 in 10 year forecasted maximum system demand.

As the customer base gets familiar with the notion of an "event," fine tuning the "all or nothing" aspects of a trigger could be assessed. If half the DR could be realized with half the price adder associated with a peak period price (or rebate level), this would provide system operators more flexibility as compared to an "all-or-nothing" approach, which does not distinguish between conditions just warranting triggering designation versus all-time peak conditions. A sensitivity analysis in this regard may be useful, but at this stage a rough cut treatment may be warranted before much fine tuning is applied.

While the long-run triggering mechanism addresses the demand side of the price equation, often it is the supply side that governs short run pricing in the market. A triggering mechanism in place today that works within the wholesale market and has the potential to work within the MRTU market uses heat rate (e.g., 15,000 BTU/kWh) to determine when the short-run supply resources are becoming scarce. This heat rate approach synthetically places the DR resources in the supply stack and dispatches the resource when the wholesale market price is met. The heat rate is calculated based on the market price for energy divided by the market-price for natural gas (e.g., $105/MWh divided by $7/MM-BTU equals a heat rate of 15,000 BTU/kWh). The near term problem with this approach is that wholesale market prices and the corresponding heat rates sometimes fail to reflect available capacity.

As the ISO's MRTU program matures, it is hoped that these proxies will give way to actual capacity pricing components. The extent to which these short-run capacity prices correlate to long-run equilibrium values, will ultimately determine the cost-effectiveness of DR programs relative to alternative supply side resources.

Triggering responsibility for price response programs that are called a day in advance should be initiated by the utility as part of its overall resource mix. It is the utilities' responsibility to procure enough resources to meet their day-ahead forecasted demand. Only during real-time emergency conditions should the ISO call upon the system reliability programs to reduce load. For ISO called events, a communications protocol for the ISO and utilities should be developed with respect to the dispatch of emergency demand response programs.[10]

b) <u>Additional Information or Analysis</u>

Analysis should focus on other operating markets to determine the means by which their trigger mechanisms function and whether they have been in place long enough to see a steady state develop that equates the value of demand- and supply-side resources. Additionally, upon MRTU deployment, market prices should be assessed to determine the existing correlation between peak period demand and market clearing prices.

If too many trigger events occur as a result of trying to meet both the objectives of curtailing demand in response to high prices as a result of erratic supply constraints and reducing system peak load to improve the system load factor, effects on customer adoption and response must be considered.

3. <u>Linkage to Market Prices and MRTU</u>

As discussed above, as long as there are strong resource adequacy requirements, short-run prices will not include an adequate capacity pricing component and market clearing prices will not be an efficient means for designing rates. Until MRTU data is analyzed to determine the degree to which capacity costs are embedded within the hourly prices, the rates containing a constructed capacity component are as useful as the market prices at achieving DR objectives.[11] For non-peak period, the MRTU pricing more closely resembles marginal cost (energy only) pricing as it represents the market price absent the capacity adders that should be present only during peak load conditions.

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[10] Consistent with the Energy Division's proposed demand response goals as articulated in the *Assigned Commissioner's and Administrative Law Judge's Ruling Revising Phase 2 Activities and Schedule*, October 1, 2007, p. A-20.

[11] Scarcity pricing may ultimately serve this function, but will not be deployed until mid-2009 and may not be relevant until after the price response loads are removed from the LSE's RAR forecasts.

G. Residential Rate Issues

1. Key Policy Issues

From SCE's perspective, the key policy issues in this category are (1) dynamic pricing under AB1X; (2) dynamic rates for low income customers; and (3) linkages to other programs.

2. Dynamic Pricing Under AB1X

a) Discussion

Participation and DR Under AB1X. As long as Water Code Section 80110 is in effect, a rebate program (e.g., PTR) provides the best opportunity to maximize response to price signals as it provides universal participation without the need for program or rate enrollment.

Rate Design Under AB1X. AB1X has forced the utilities to be creative in designing their time-differentiated rates. Currently, the AB1X "compliant" TOU rates at PG&E and SDG&E have TOU differentiated rates applied within each usage tier. As complex as this is, it seems to be the only structure that provides both the strong conservation price signal along with some dynamic pricing structure which does not contain significant structural benefits to high usage customers. While complying with the provisions of Water Code Section 80110, the notion of rate simplicity and understandability is lost in the process.[12]

In D.06-10-051, the Commission ruled that as long as the AB1X rate protections are contained in the default rate option to residential customers, customers may voluntarily choose an alternate rate program that does not include these rate protections. A key question then becomes, how many customers would voluntarily abandon rates that provide discounts of as much as 25% to lower tier usage (relative to the average rate) for the

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[12] SCE's rate structures are also complex in that they attempt to provide some measure of AB1X protection by including a baseline credit.

"opportunity" to try a dynamic pricing rate structure? Any type of cost-based discount as a result of TOU consumption would not provide such discounts, so the answer would seem to be that only very high usage customers who are already paying rates well above their cost-to-serve would opt for such dynamic pricing structures. The question facing the rate designer is what rate level should the TOU rates balance to? A traditional TOU structure balanced to the average residential rate level would provide a significant structural benefit to high usage customers simply by allowing them to avoid the high subsidies associated with AB1X compliant tiered rates. The tiered TOU rate structures prevent this type of rate migration.

b) Additional Information or Analysis

Participation rates and price elasticities have a significant impact on DR. With limited empirical data, it is not known whether customers respond better to Critical Peak Pricing (CPP) signals relative to PTR (i.e., carrot versus stick approach). Customers' behavior vis-à-vis CPP and PTR should continue to be analyzed to draw more conclusive results.[13]

c) Recommendation

To maximize customer participation while Water Code Section 80110 is effective, the Commission should adopt a policy to utilize a rebate structure (e.g., PTR). Upon the expiration of Water Code Section 80110, consideration should be given to alterative dynamic pricing structures, including default ones.

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[13] For example, in a recent Ontario Energy pilot study where customers self-selected into the program, the rebate structure provided 30% less demand response compared to peak time charges. (*See* Ontario Energy Board Smart Price Pilot Final Report, July 2007, prepared by IBM Global Services and eMeter Strategic Consulting.) A smaller study performed for Anaheim Utilities showed comparable elasticities. (See SDG&E A.05-03-015, Errata to Chapter 6 Demand Response Benefits, Revised September 19, 2006, Testimony of Dr. Stephen S. George.)

3. Dynamic Rates for Low Income Customers

a) Discussion

The purpose of the California Alternate Rate for Energy (CARE) program is to provide a measure of affordability to low income customers. To expose CARE customers to dynamic pricing programs, the conflicting policy objectives of providing affordable rates and relatively strong price signals to modify consumer behavior need to be reconciled. Since 2001, the Commission has significantly increased the effective CARE discount to levels well above the adopted 20% discount. With the vast majority of CARE customers' usage falling below the existing 130% of baseline quantity which is subject to capped rates mandated by AB1X, state policy precludes any pricing program that could result in increased bills to customers whose low income should make them actually more responsive to changes in prices.

b) Recommendation

Since the CARE program comprises nearly 25% of all residential customers state-wide, it is important that they participate in dynamic pricing programs. While the value to the system of an avoided peak kWh is the same regardless of the end use customers' rate structure, paying the same value for an avoided kWh for both CARE and non-CARE customers is inequitable given that the rate levels for CARE customers are discounted by more than 20%. Without discounting the credits or scaling back the peak period charges to be proportional to average rate levels, the incentive to provide DR would be too high for low income customers. Accordingly, the Commission should consider adopting a policy that adjusts the time-differentiated rate levels (or credit provided for DR) in accordance with the discounted average rate level for CARE customers.

4. Linkages to Other Programs

a) Discussion

The proposed AMI-enabled residential rates in California are probably the most complex in the nation due to the combination of conservation objectives (tiered rates), price restrictions by tier and income level, and now price response objectives. SCE is concerned that trying to reflect all of these objectives in residential rate structures may become too confusing for customers.

A/C Cycling. A/C cycling has proven to be the most dependable program to address the Commission's reliability goals, flatten the load curve, and better reflect the marginal cost of service by providing credits in exchange for customers' making their load available for curtailment. Despite several attempts to do so, however, these direct load control programs have not been considered to be price response programs despite the fact that customers do not provide this service "gratis." In addition, since price response and reliability programs both use the concept of avoided or marginal generation capacity costs as justification for their high prices or credits, respectively, care must be taken to not pay customers twice for the same load by providing clear distinctions between the programs. (*See* Section I, Relationship to Reliability-Oriented and Other Demand Response Programs, for more discussion regarding the relationship to other DR programs).

Increasing Block Rates. The current default increasing block rates provide an energy conservation signal that is well above any marginal cost of service estimate due to AB1X restrictions. To the extent there are crossover benefits from the strong conservation signals on peak period usage, the tiered rate structure has DR benefits. Unfortunately, the extent to which these tiered rates have impacted total usage, let alone peak period usage, is unknown. There is a study under way whereby the utilities (SCE, SDG&E, and PG&E) have provided historical billing information to the University of California Energy Institute (UCEI) to assess the price elasticity impacts of tiered rate changes since 2001 (TOU impacts are out of scope for this particular project).

b) Recommendation

As discussed above, SCE recommends that the benefits from dynamic pricing and reliability programs must continue to be assessed to minimize double payments for the same load reductions. SCE also recommends that the effects of increasing block rates to fulfill the Commission's conservation policy goals should continue to be assessed against secondary benefits of peak load reductions.

H. Critical Peak Pricing

1. Key Policy Issues

From SCE's perspective, the key policy issue in this category is the CPP rate, including CPP cost recovery for a variable number of events and customer response to CPP.

2. Critical Peak Pricing Rate

a) Discussion

CPP rates are designed to discourage energy consumption during periods when temperature or market triggers indicate potential capacity shortages in the following day. In designing the CPP rates, a capacity cost proxy reflecting the long-run value of capacity is used as the basis for capacity benefits reflected in retail rates. The CPP construct only considers generation capacity, both from a benefit and a cost perspective. CPP rate structures provide no reliability benefits due to day-ahead triggers. In fact, the program's value is limited in the short run because no capacity costs can be avoided until the CPP price response loads are removed from the RAR forecasts.

As long as there are adequate short run supply resources, scarcity pricing that reflects capacity will not materialize in the market. The utilities have generally addressed this by constructing a total price consisting of the short-run energy price and adding a long-run capacity price converted to a cents per kWh price component. This capacity price is typically a loss adjusted annualized cost of capacity (e.g., $80 per kW-year) discounted to allow for a reduced capacity value relative to a supply-side resource (e.g., 40% discount to allow for limited calls in a day-ahead market) and allocated evenly across some specific design number of hours (e.g., 60 hours, consisting of 15 events of 4 hours each). This capacity "adder" (($80*(1 - 0.40)) / 60 = $0.80/kWh) is then typically added to the relevant energy rate to formulate the total CPP rate over the limited set of hours.[14] To mitigate cost recovery concerns, CPP rates can be designed for fewer hours than are actually expected to be called. For example, if 50 hours are used for rate design, the capacity adder would be $0.96/kWh. The 20% increase in the CPP rates affords greater flexibility in triggering CPP events given that a fewer number of events are required to recover utility's authorized revenues; however, the greater number is still available to meet event triggers.

b) **Additional Information or Analysis**

Parties should fully explore customers' willingness and ability to respond to CPP events. Potential benefits must be weighed against business disruptions driven by a dynamic pricing response. In market research of large customers (>200 kW), potential CPP bill savings proved to be lower than what a majority of customers would expect for a given level of response. Utilities should use this type of evidence to target their demand response efforts.

Also, as discussed at the DRRC workshop, a method to assess the relative efficiency gain for each additional level of rate complexity should be developed. We should be attempting to answer "80-20" type questions such as "Are we able to achieve 80% of the potential efficiency that a CPP program provides us by a simple TOU rate with only 20% of the complexity?"

c) **Recommendation**

SCE recommends that in the short run, CPP rates be designed to mitigate revenue under collection through the use of soft triggers, and a "hedging" structure should be

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[14] This is generally consistent with the methodology described in Appendices A and B of the Joint Utilities' Demand Response Cost-Effectiveness Filing.

built into the rate design. A trigger mechanism should also be reevaluated or adjusted to prevent a situation where the program is called too frequently. (*See* Section E, Hedging, and Section F, Sources of Triggers and Prices for Dynamic Prices, for more information).

I. Relationship to Reliability-Oriented and Other Demand Response Programs

1. Key Policy Issues

From SCE's perspective, the key policy issues in this category are (1) coordination with reliability programs; and (2) reliability benefits of dynamic rates.

2. Reliability Benefits of Dynamic Rates

a) Discussion

In this section, SCE discusses in greater detail the impact of dynamic pricing structures on existing DR programs, how the attributes of dynamic pricing, price responsive and reliability DR programs overlap and finally to recommend how such overlaps may be addressed in order to mitigate double counting and double payments.

There are three types of rate-related approaches to achieving DR. The first is dynamic pricing. Here, the end-use customers are exposed to a price signal through their rates when the utility needs load reduction to occur. What makes a price response rate dynamic is that the price signal and its duration may vary from hour to hour, day to day or season to season.[15] The trigger to launch a dynamic pricing event may be based on the wholesale price of electricity (or a proxy thereof) or system conditions that are not directly related to price, such as temperature or system operating reserves. It may be called either on a day-ahead or a day-of basis.

Thus, a dynamic rate has attributes of a price response DR program but may also have some attributes of a reliability program. Current dynamic pricing programs that

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[15] A TOU rate is price responsive but it is not dynamic.

have these overlapping attributes are CPP[16] and the Demand Bidding Program (DBP).[17] The price signals provided under these tariffs are not currently tied to a wholesale price and in the case of DBP in particular, the incentive may exceed the real time price in the market by a significant amount. Similar to a reliability program, the DBP incentive may reward customers in excess of the economic value of the energy reduction for curtailing load. SCE has also proposed PTR for residential customers, which pays for load reduction during critical periods. This rate will likely be similar to CPP in terms of the trigger and notification.

The second type of program is the traditional reliability based program such as large power interruptible I-6, Base Interruptible Programs (BIP), Agricultural and Water Pumping Interruptible and the Summer Discount Plan (A/C cycling). These reliability DR programs are dispatched by SCE when the CAISO declares system emergencies associated with supply shortages during system peak conditions or a transmission line outage. Reliability DR programs may also be used to mitigate localized distribution emergencies. These programs and associated tariffs reduce the likelihood of forced curtailment of electric service to firm service customers, and are launched only on a day-of basis with some load curtailment being as soon as 15 minutes from the time of notice from the ISO.

Reliability programs provide incentives to customers to curtail load primarily through a fixed payment similar to a capacity reservation fee. Customers are paid the incentive regardless of whether a reliability event is called; however, if such an event is called customers must curtail load. The reduction is enabled by an installed load control device or voluntarily subject to significant penalties for non-performance. Customers on reliability DR programs do not receive a price signal during the curtailment event and therefore these programs are considered neither dynamic nor price responsive DR.

The third program approach is a hybrid of price response and reliability, but does not have the attributes of dynamic pricing. In this instance, the trigger to launch the

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16 SCE's CPP has a heat rate trigger, day-ahead notice, which provides a price signal during critical events. SDG&E's Schedule EECC-CPP-E has a CPP rate structure but is used for day-of system or local emergencies.

17 DBP has a heat rate trigger for day-ahead and CAISO-declared Stage 1 for day-of, and offers an energy rate discount during events.

load curtailment is price (currently using heat rate as a proxy), but the end-use customer does not receive a price signal during the event. The end-use customer is required to commit to a load reduction, either on a day-ahead or day-of basis, and is paid a monthly reservation fee on a $/kW basis in exchange for the commitment to reduce load when called. The customer is paid regardless of whether there is an event but is charged a significant penalty for non-performance. This program may also offer an energy payment for events triggered based on wholesale electricity prices. This hybrid program design is very similar to that of reliability programs. Examples of this hybrid approach are the Capacity Bidding Program (CBP) and the Curtailment Service Provider (CSP) contracts recently entered into by the utilities.[18]

The dynamic pricing programs such as CPP, DBP and PTR generally are triggered on a day-ahead basis before either the hybrid or the reliability programs. Thus, these dynamic programs may actually reduce the need to call the hybrid or reliability programs on any given day in the short term, and in the longer term may reduce the level of enrollment needed in these reliability programs. Nevertheless, the Commission should be cautious in relying too heavily on dynamic pricing programs to mitigate system emergencies. Dynamic pricing programs are voluntary and while the customer may pay more for electricity consumed during an event, the level of the price signal may not be sufficient to incentivize all customers to reduce load. Neither are there any explicit penalties associated with non-performance. The overall load reduction from dynamic pricing relies on changes in customer behavior and currently, SCE does not have sufficient experience with dynamic pricing on a large scale across all customer segments to be able to accurately predict performance during an event. Therefore retention of the hybrid and reliability programs is imperative. Additionally, in order to maximize participation in dynamic pricing programs, the dynamic rates should be designed so as to allow participation in reliability programs, yet avoid potential double payments. This issue will be discussed in the next section.

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[18] Under the CSP contracts, the utility will notify the CSP to curtail the load of its customers. The program design may allow both day-ahead and day-of notification and is triggered based on heat rate.

b) **Recommendation**

SCE recommends that the Commission consider the fact that load reductions from dynamic pricing rates are not as certain as those achieved through load control programs or SCE's other reliability programs. Therefore, reliability programs should always be considered an important element of the overall DR portfolio. Further, as will be discussed below, in order to maximize participation in dynamic pricing programs, the issue of dual participation in both dynamic pricing and reliability programs should be addressed in this proceeding.

3. **Coordination with Reliability Programs**

a) **Discussion**

Dynamic pricing tariffs and SCE's traditional reliability programs offer a portfolio of DR resources that allow the grid operators the option to "ramp up" programs (day-ahead to less than 10 minutes notification) to address system reliability.

However, dynamic pricing, reliability and hybrid programs have overlapping attributes in terms of when they are called and the triggers used. Therefore, in developing dynamic pricing programs the issue of double counting of the load reductions for planning and operational purposes must be addressed as well as the issue of double paying a customer who may be on more than one program or rate simultaneously.

The Commission has laid down the general rule that a customer can participate in a program that pays an incentive on an energy basis (pay for performance) and at the same time participate in a program that pays an incentive on a per kW basis (reservation fee). For example, a customer could participate in DBP and I-6 at the same time, but if a day-ahead DBP was already scheduled at the same time that an I-6 event was launched, the customer's obligation on I-6 would take precedence and the customer would not be eligible for the DBP incentive. The double counting of MW has not yet been an issue operationally,[19] but will need to be addressed in the MRTU integration of DR into the ISO's operations. For example, in anticipation of an ISO day-ahead electricity market, the utilities recently began to provide the ISO a day-ahead forecast of DR MW when an event is called. If interruptible events were to be called for the same period, the ISO may count both the day-ahead MW and the interruptible MW when it assesses the need to call for interruptions. This situation – and most dual participation issues – can be easily resolved by means of adjusting the day-ahead forecast, but it does highlight a problem that needs to be addressed.

However, coordination issues between some other programs are more difficult to resolve. For example, CPP is a dynamic pricing, price responsive DR rate. Currently, an SCE CPP customer may not participate in a reliability or hybrid program.[20] In order to achieve more price responsive MW of DR on CPP, interruptible program or hybrid program participants could be allowed to simultaneously participate in CPP. These interruptible customers are accustomed to reducing load and are very reliable in doing so. Further, all things being equal, SCE's CPP is also likely to be called for economic reasons rather than an emergency event. There could potentially be many more participants and MW enrolled in CPP if dual participation were allowed. However, a CPP participant receives its incentive through lower electricity rates during periods when events do not occur. If a CPP customer were to be on BIP, for example, and reduce load, it would receive both the BIP reservation payment (which is paid whether there is an event or not) and the CPP incentive. Another dual participation scenario is CBP and BIP. Although technically neither program is dynamic pricing, there have been

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[19] Monthly reporting of MW does not consider scenarios under which programs are called, (e.g. one or the other called or both called), but rather reports the expected MW if each individual program is called.

discussions concerning dual participation performance measurement and double payment issues. Currently, SCE does not allow dual participation in these two programs.

b) **Recommendation**

The question of dual participation on dynamic pricing and other DR tariffs and programs should be explicitly addressed in this proceeding, and take into account the future needs of the ISO.

J. **Timing of Tariff Development and Roll-Out**

1. **Key Policy Issues**

From SCE's perspective the key policy issues in this category are the timing and targeting of dynamic pricing tariffs.

2. **Timing and Targeting of Tariffs**

a) **Discussion**

Timing of Dynamic Tariffs. Most dynamic prices and time differentiated rates should become available as the advanced meters are deployed. As detailed in A.07-07-026, SCE is planning to begin a full-scale deployment of smart meters to all residential and business customers (below 200 kW) in January 2009 with estimated deployment completion in 2012. SCE will have time-differentiated rates available to all customers at the onset of the deployment.[21] That is, enrollment into dynamic rates will become available shortly after the meter is installed.

Migration Strategy. Additionally, for customers that will be provided "default" or "mandatory" dynamic rates, consideration should be given to a migration strategy.

Continued from the previous page

[20] SCE's A/C cycling program is the exception in that it does allow dual participation in CPP.

[21] Edison SmartConnect™ enabled dynamic rate structures will be filed in SCE's 2009 GRC Phase 2 to become available in October 2009.

In other words, rather than immediately exposing such customers to a new dynamic rate and creating a measure of rate shock, customers could be first exposed to dynamic rates on a smaller scale, and then later migrated to the desired rate. For example, in A.07-07-026, SCE proposed default TOU rates for its medium C&I customers (20 to 200 kW) as the meters are installed during the deployment period from 2009 to 2012. Customers in this rate group would be defaulted to TOU rates on which some customers would be better off and some worse off. As described in A.07-07-026, SCE estimated that 51% would remain on the TOU rates and 49% would eventually opt out to the OAT. Presumably, the 49% of customers who opt out would experience lower customer satisfaction, as they were "forced" into paying a higher rate for some period of time. Alternatives to this situation could be (1) bill protection, (2) opt-in during a transition phase, then default at a later date, (3) default only those customers that would benefit from the TOU rate after a sufficient data collection period, or (4) provide historical usage information and inform customers that would be better off on the TOU rates to facilitate the customers' opt-in decision.

The MRTU deployment scheduled for early 2008 is not of consequence as SCE has a general understanding of what to expect from the MRTU deployment. While the key MRTU benefit is to provide hourly prices in a day-ahead market, there is little customer interest in electricity rates that vary by only a few cents per kWh. In the near term, it will be the constructed capacity rates and associated credits that will dominate customer DR.

b) **Recommendation**

As discussed above, SCE recommends that dynamic rates for each rate group should become available to each customer shortly after the AMI meter is installed, and the Commission should also consider adopting a migration strategy for customers who will be exposed to default and mandatory dynamic rates.

III.

CONCLUSION

SCE appreciates the opportunity to provide these comments and looks forward to working with the Commission and other interested parties to establish a well-designed dynamic pricing policy.

Respectfully submitted,

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October 5, 2007

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMMENTS ON THE SUPPLEMENTAL SCOPING MEMO AND ASSIGNED COMMISSIONER'S RULING UPDATING ISSUES LIST, SCHEDULE, AND CATEGORIZATION on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this **5th day of October, 2007**, at Rosemead, California.

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